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Hydrocarbon Generation Potential and Thermal Maturity of some Coal and Shale of Okobo Area, Mamu Formation, Southern Nigeria

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Abstract

Maastrichtian Mamu Formation's coal and shale succession exposed at the Okobo Coal Mine region of Anambra Basin in Kogi State, Nigeria were analyzed to assess their hydrocarbon generation potential and thermal maturity. This assessment was carried out using geochemical tools (TOC and Rock-Eval pyrolysis).

Shale samples of the Mamu Formation have TOC contents from 0.78wt%-7.68wt% (mean-5.09wt%), SP values from 0.5-22.31 (mean-11.16), HI values from 56-286 (mean-186), Tmax values from 423-439^{0}C (mean-431^{0}C). Samples of coals exhibited TOC values from 48.23wt% to 52.81wt% (mean-50.75wt %), SP values from 125.61 to 209.96 (mean-148.03), HI values from 244-390 (mean-286) and average Tmax value is 421^{0}C. The organic matter is of type II and type II/III kerogen, having good to excellent source rock potential, which can generate oil as well as gas. Thermal maturity determined from Tmax and production index indicates that the organic matter is in immature to early mature stage, and can generate oil and gas at higher maturity stage. The hydrocarbon generation potential of organic matter present in coal and shales is good and capable to generate oil and gas at higher maturation stage.

Keywords: Mamu Formation, TOC, Hydrocarbon Generative Potential, Thermal Maturity, Anambra Basin, Nigeria.

Introduction

Anambra Basin comprises of post Santonian sequence of about 12km sedimentary fill in its thickest part. It corresponds to the western complimentary syncline to the emergent Abakaliki Anticlinorioum in the Lower Benue Trough southeastern Nigeria (Fig. 1) and has been a major geological area for coal exploration and exploitation since 1909. The Mamu Formation in the Anambra Basin has attracted numerous attentions due to the abundant coal resource that it's hosted. This

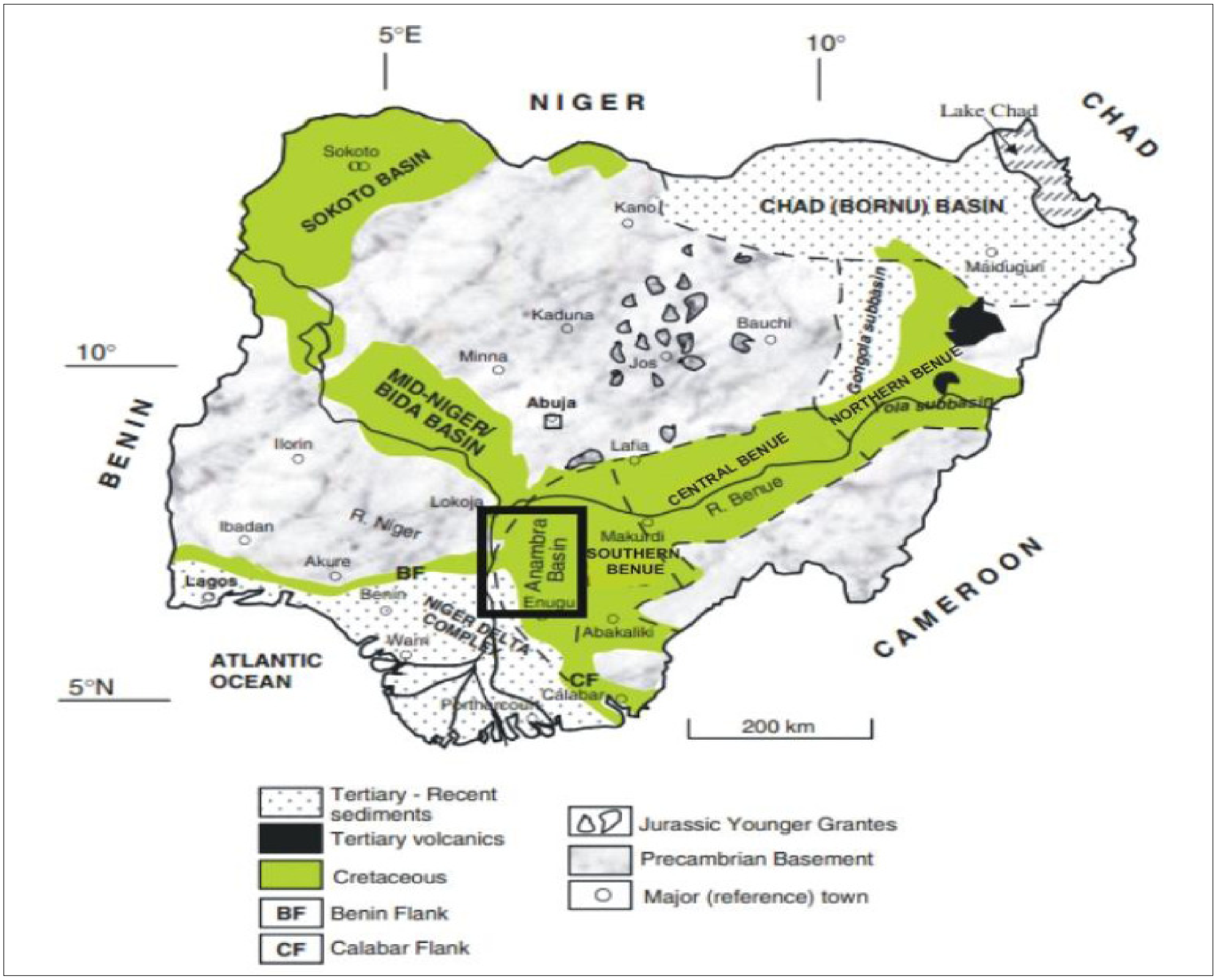

Fig. 1. Generalized geological map of Nigeria showing Anambra Basin (modified from Obaje, et al., 2004)

Formation hosts the sub-bituminous coal succession of the southern Nigeria. The first basin where intensive oil exploration was carried out in Nigeria is Anambra Basin in the southern part of Nigeria (Adebayo et al., 2015). The study area (Okobo Coal Mine) falls within the northern part of the Anambra Basin and belong to Mamu Formation. It is located in Okobo, a small town in Enjema District of Ankpa Local Government Area on Sheet 249SW (Fig. 1) between 354729 and 358407 in the Easting's and 829224 and 832923 in the Northings (32N UTM, WGS 84). It is located around Longitude E 007° 42□ 41.0□ and Latitude N 07° 30□ 31.0□ and the total area covered is approximately 13.6 square kilometers. It is bordered in the east by Benue State and in the South by Enugu State.

The search for hydrocarbons in the Cretaceous source rocks in the Nigerian inland sedimentary basins has been a major task for many decades. Exploration campaigns in the inland basins have been undertaken with the aim of expanding the national exploration and production base and adding to the proven reserves. The drive for successful hydrocarbon exploration and production in the inland sedimentary basins of Nigeria necessitates detailed evaluation of the generative potential of the source rock facies in the Anambra Basin. The efforts were to boost the oil and gas exploration and

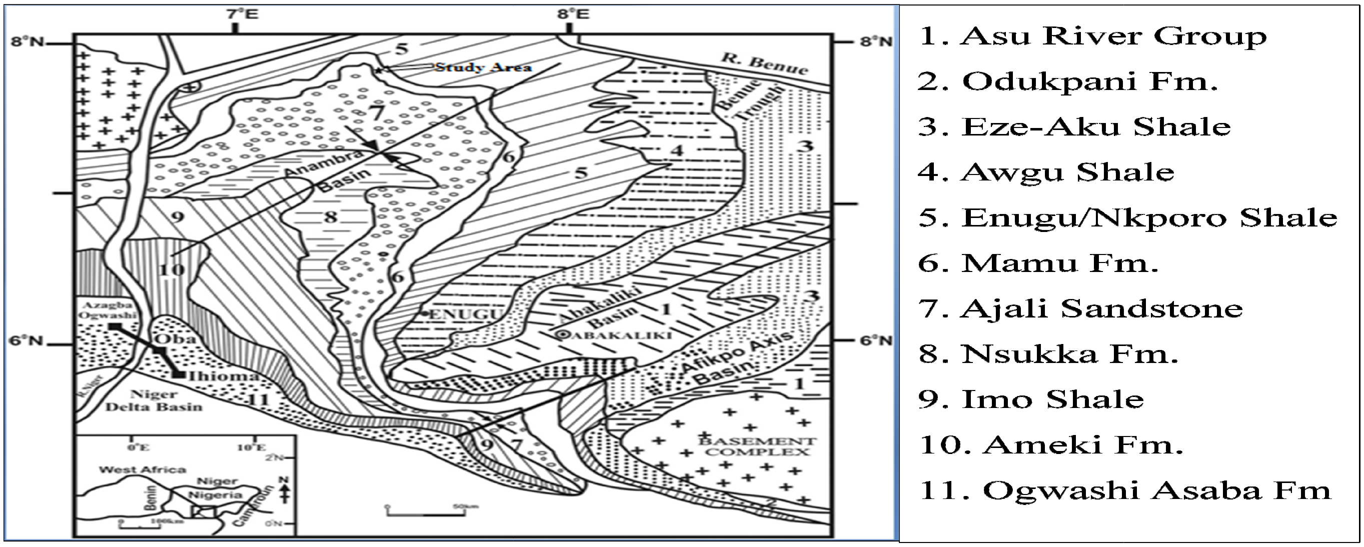

Fig. 2. General Geological Map of Southeastern Nigeria (Akande et al., 2015b)

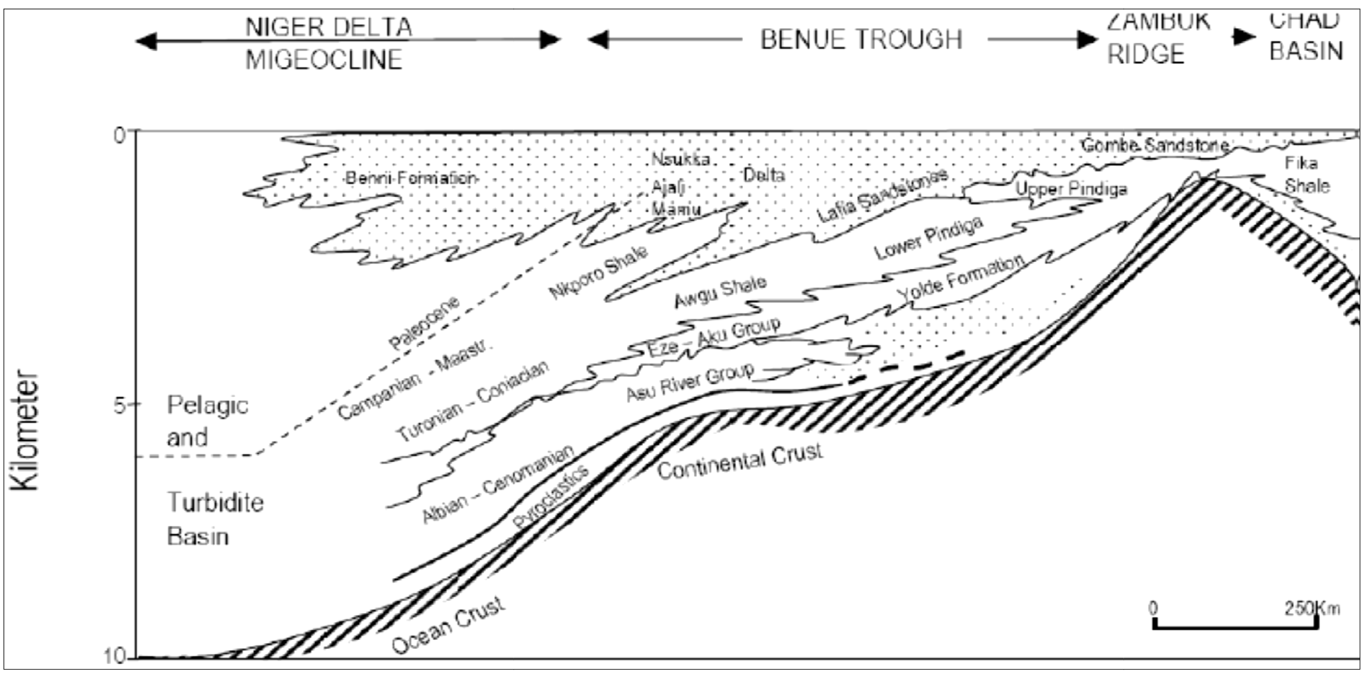

Fig. 3. Generalized stratigraphic NE /SW framework from the Niger Delta through the Benue Trough to the Chad Basin illustrating the unconformity bound stratigraphic sequences of the basins (Akande et al., 2011)

production activities and also adequately tap the natural resources in the country. Coal beds are now a potentially significant source of hydrocarbons and increasingly are becoming exploration targets in many parts of the world. Examples of coal-derived hydrocarbon have been reported from the Kutai Basin-Mahakam Delta (Indonesia), Junggar, Tarim and Turpan Basins (Northwestern China), Cooper Basin (Australia), Taranaki Basin (New Zealand), and Karoo Basin (Tanzania).

Agagu and Ekweozor (1982) reported that the Awgu and Nkporo shales constitute the main source and seal rocks in the basin while Ekweozor and Gormly (1983) describe the Nkporo shale as an example of a marine source rock composed of type II/III kerogens with low but consistent contribution from marine organic matter. The work of Unomah and Ekweozor (1993) reveals that the organo-facies of the Nkporo Shales are provincial with the Calabar Flank having the highest oil potential whereas those in the Anambra/Afikpo Basin are gas prone. According to Akande et al., (1992), the lower Maastrichtian Coals of the Mamu Formation are characterized by moderate to high concentrations of huminite and some minor amounts of inertinites and liptinites. Recent work on the hydrocarbon potential of the basin include Ehinola *et al.* (2005), Akande et al., (2007), Akande et al., (2008), Ogala (2011),Akande et al., (2011), Nton and Bankole (2012), Uzoegbu et al., (2014), Akande et al., (2015a), Akande et al., (2015b), and others. They all suggest good prospect for hydrocarbon potential within the basin.

This work presents the hydrocarbon generation potential and thermal maturity of the Okobo coal and shale succession affiliated with Mamu Formation based on Rock-eval pyrolysis.

Geology of the Area

The geologic strata of the Anambra Basin were deposited in a syncline initiated by the major folding episode in the Lower Benue Trough Basin during Late Cretaceous times (Fig. 2). The Lower Benue Trough is the southern portion of the Benue Trough (Fig. 2 and Fig. 3) that is believed to have originated as a failed arm of anaulacogen at the time of the opening of the South Atlantic Oceans during the separation of the African Plate and the South American Plate (Olade, 1975). In southern Benue Trough, the Albian sediments are the oldest Cretaceous sediment deposited as first marine sediments due to Albian marine transgression in the Abakaliki area. This was followed by the Cenomanian Odukpani Formation in the Calabar Flank (Reyment, 1965). Further transgression and regression took place during Turonian period which deposited Eze-Aku Formation and Awgu Shale (Murat, 1972).

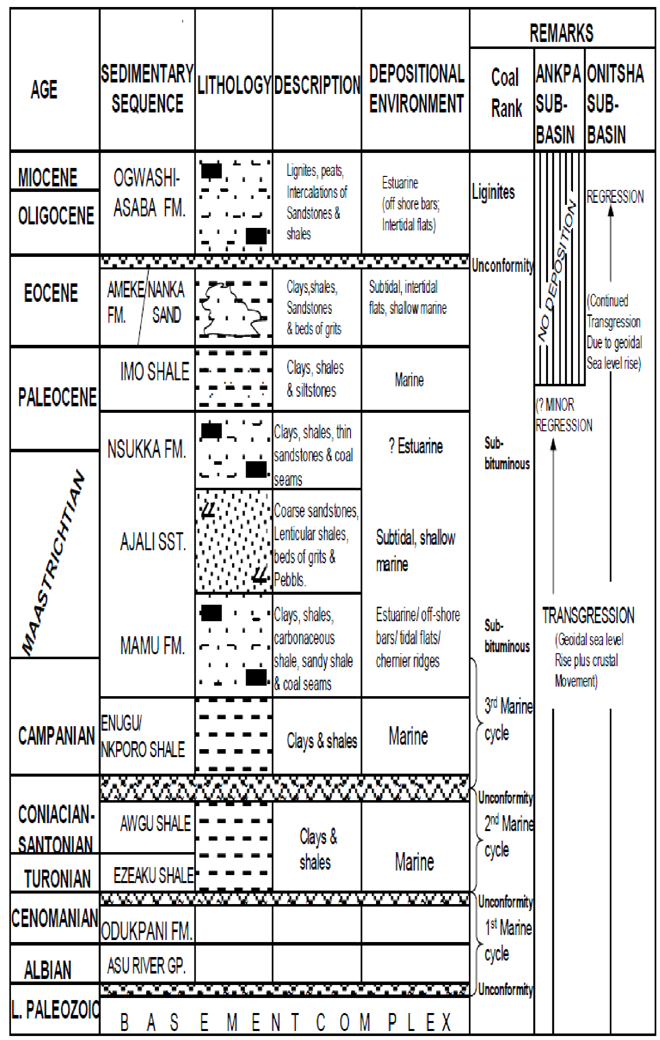

Fig. 4. General Stratigraphy of the Lower Benue Trough Basin, Southeastern Nigeria (Akande et al., 1992)

During the Maastrichtian, the Anambra Basin became silted up and extensive thickly vegetated

swamps developed near sea level, on top of a broad delta fan built up by rivers bringing sediments from the hinterland. Sedimentation in the Anambra Basin commenced with the Campano – Maastrichtian marine and paralic shales of the Enugu and Nkporo Formations (Fig.4). These basal units are overlain successively by the coal measures of the Mamu Formation, the Ajali Sandstone, and the Nsukka Formation. In the Anambra Basin, basin infilling was punctuated by incursions of marine sedimentation followed by continental sedimentation that provided conditions conducive to the deposition of Coal.

Enugu/Nkporo Shale

The basal facies of the late Cretaceous sedimentary cycle in the Anambra Basin is the Nkporo Shale which indicates a late Campanian age. It consists of a sequence of bluish to dark grey shale and mudstone, sandy shales, thin sandstones and shelly limestone beds. The shaly facies grade laterally to sandstones of the Owelli and Afikpo Formations in the Anambra Basin. The Enugu / Nkporo Formations are essentially marine sediments of the third transgressive cycle. These, in most parts of the Anambra Basin is overlain by the Lower Maastrichtian sandstones, shales, siltstones and mudstones and the interbedded coal seams of the deltaic Mamu Formation(Akande et al., 2011).

The lithology of Enugu shales consists mainly of carbonaceous shales and coals within the upper half deposited in lower flood plain and swampy environments. The sediments are normally associated with siderites and pyrites which are early diagenetic minerals (Omoboriowo et al., 2012).

Mamu Formation

The Mamu Formation succeeds the Upper Campanian lateral facies associations. The age ranges from Lower to Middle Maastrichtian from south to north, and is accompanied by both vertical and lateral facies changes (Ladipo et al., 1988). The thickness of the formation varies across the basin, ranging from 100m to over 1000m. The lithologic associations include shales and sandstones, with some limestone in the south and coal seams in the central to the upper parts of the basin and the typical depositional environments include distributaries/estuarine channels, barrier foot, swamp and tidal flats (Uzoegbu et al., 2014). These sandstones, shales, sandy shales, and coals which contain at various level carbonaceous layers, were referred to as “Lower Coal Measures" (Simpson, 1954).

Ajali Sandstones

The Ajali sandstones consists of mineralogically supermature, medium to coarse grained, moderately sorted quartz arenites of about 300m thick extending across the entire basins as a sheet-like sandbody, and into the Middle Niger Basin (Uzoegbu et al., 2014). The formation is slightly diachronous, ranging from Middle to Late Maastrichtian from south to north. The sediments are unconsolidated and kaolinite matrix constitutes less than 5% of the total rock volume (Uzoegbu et al., 2014). The clays also occur as thin and laterally extensive beds (< 1 m usually) which intercalated with the sands and act in places as the only permeability barrier in the sequence.

Cross bedding is the dominant sedimentary structure of the formation. It is associated with reactivation surfaces, mud drapes, tidal bundles, backflow ripple channels cut and fills, lateral accretion surfaces, as well as skolithosand ophiomorpha ichno genera (Ladipo et al., 1992). These structures characterized the formation over the entire basin, and suggest tidal origin within a

shallow marine environment. Paleocurrent trends across the basin suggest a depositional environment similar to the southern part of the North Sea, which is characterized by helicoidal tidal currents and dominated by large-scale sand waves (Dike, 1976).

Nsukka Formation

The Nsukka Formation (Upper Coal Measures) conformably overlies the Ajali Sandstone Formation and occurs from the north of Awka to the upper Ankpa sub-basin. The lithology is mainly interbedded shales, siltstones, sands and thin coal seams , which have become lateritized in many places where they characteristically form resistant capping on mesas and buttes (Uzoegbu et al., 2014). The formation is diachronous, spanning upper Maastrichtian into Danian. Depositional environment has been suggested to be similar in many ways to the Mamu Formation (Lower Coal Measures) i.e. transitional/shoreline, mud flat and swamps, deposited during a largely regressive phase.

Imo Shale

The Imo Shale developed as thick bluish to greyish clays and marine shales with a maximum thickness of about 500m. It is of Paleocene age and overlies the upper coal measures of the Nsukka formation and appears to thin out west of the River Niger towards Araraomi and Gbekebo, with thickness of 200m and 180m respectively (Reyment, 1965). East of the River Niger, within the formation, however, lenses of sands occur.

The Imo Formation is overlain by the regressive sandstones succession of the Ameki Formation and the overlying sandstones, shales and lignite beds of the Oligocene / Miocene Ogwashi – Asaba Formation; These Tertiary units constitute the proto- Niger Delta Eocene to Recent sequences in the subsurface (Akande et al., 2011).

Methodology

Evaluation of the potential source rock uses the methods of geochemistry to quantify the nature of organic-rich rocks which contain the precursors to hydrocarbons, such that the type and quality of expelled hydrocarbon can be assessed. In terms of source rock analysis, several facts need to be established. Firstly, the question of whether there actually is any source rock in the area must be answered. Several authors demonstrated the usefulness of organic geochemistry in assessing the generative potential and characteristics of source rocks. However, the quantity, quality and thermal maturity of the source rocks in the study area are examined based on organic geochemistry. Rock-Eval pyrolysis has been widely used in the industry as a standard method in petroleum exploration. Twenty (20) samples comprising of eleven (11) shales and nine (9) coals were selected for Rock Eval/TOC analysis at Australian Laboratory Services (ALS) Limited, Houston Texas to determine their hydrocarbon generation potential, thermal maturity conditions using Rock-Eval II pyrolyser machine with TOC module.

The samples were heated in an inert atmosphere to 550^0C using a special temperature programme. The samples were heated to a temperature of 300^0C for 3min to generate the first peak (S_1) which represents free and absorptive hydrocarbon present in the sample. This was followed by programmed pyrolysis to 550^0C at 250^0C/min. The second peak (S_2) represents the hydrocarbon generated by the thermal cracking of the kerogen. At the same time, the CO_2 produced during the temperature interval was recorded as the S_3peak. Both the S_1 and S_2 hydrocarbon peaks were measured using a flame

Ionization Detector and a splitting arrangement permitted the measurement of S_3 peak by means of a Thermal Conductivity Detector (TCD). Other parameters obtained from the instrument include Tmax, that is temperature corresponding to the maximum S_2 peak, hydrogen index (HI), oxygen index (OI) and production index (PI).

Results and Discussions

Much of modern petroleum geochemistry depends upon accurate assessment of the hydrocarbon-source capabilities of sedimentary rocks. Exposed samples of coal and shale from the Okobo coal mine in Mamu Formation were assessed geochemically to determine the richness and quality of the organic matter in the rocks. Twenty (20) samples comprising of nine (9) coals and eleven (11) shales were analysed. The criteria for the source rocks evaluation were adapted and simplified from Tissot and Welte (1984), Peters and Cassa (1994) and Akande et al., (2011) and Akande et al., (2015) to interpret the Total Organic Carbon Content (TOC) and Rock-Eval result.

Total Organic Carbon Content

Almost all measurements of the amount of organic matter present in a rock are expressed as TOC values in weight percent of the dry rock. Because the density of the organic matter is about one-half that of clays and carbonates, the actual volumes percent occupied by the organic material is about twice the TOC percentage. It is a necessary prerequisite for sediment to generate oil or gas (Conford, 1986). Interpretation of TOC values does not simply focus on the quantity of organic matter present. A rock containing 3% TOC is likely to have much more than six times as much source capacity as a rock containing 0.5% TOC, because of the type of kerogen preserved in rich rocks is often more oil-prone than lean rocks. We therefore use TOC values as screens to indicate which rocks are of no interests to us (TOC < 0.5%), which one might be of slight interest (TOC between 0.5 % and 1.0%), and which are definitely worthy of further consideration (TOC > 1.0%).

From the TOC result, the nine (9) samples of coal in the study area range from 48.23 wt% - 52.81 wt% with an average TOC value of 50.75 wt% (Table 1). The eleven shale samples range from 0.78 wt% - 7.68 wt% with an average TOC value of 5.09 wt % as shown in Table 1. The highest concentrations of organic matter in coals are present in the north-western part of the study area with average TOC values of 52.15 wt%. While the highest concentrations of organic matter in shales are present in the south-eastern part of the study area with average TOC values of 6.32 wt%. Most of the samples have TOC values in excess of 2.0 wt% with none with TOC less than 0.5 wt%, and such levels of organic enrichment are considered as very good to excellent source rocks for hydrocarbon generation (Peters and Cassa 1994). Whereas, a classification as a possible oil source rock requires a minimum of 1.0 wt% TOC although a threshold as low as 0.5 wt% TOC are however considered in gas prone system (Bissada 1982, Akande et al., 2011). The organic matter content corroborates with high organic matter productivity and preservation expected in the deltaic environment as inferred from other study. It is safe to also suggest that the shale samples were deposited and formed in a fairly anoxic environment as indicated.

Many rocks with high TOC values, however, may have little oil-source potential, because the kerogens they contain are usually woody or highly oxidized. Thus high TOC values are a necessary but not sufficient criterion for good source rocks. We must still determine whether the kerogen present is in fact of good hydrocarbon-source quality. This leads to

Rock-Eval screening of the potential source rocks facies.

Rock Eval Pyrolysis

Successful petroleum exploration relies on detailed analysis of the petroleum system in a given area. Identification of potential source rocks, their maturity and kinetic parameters, and their regional distribution is best accomplished by rapid screening of rock samples (cores and/or cuttings) using the Rock-Eval pyrolysis approach. This is in fact that organic carbon content alone cannot be used to establish the presence of potential and effective petroleum source rocks in view of the constraints that different organic matter types have different hydrocarbon yield for the same organic carbon content, a more direct measure of source rock capability to generate hydrocarbons is required for detailed assessment (Katz 2006).

The results obtained from the pyrolysis are presented in Table 1 including Rock-Eval parameters (S1, S2, S3, and Tmax) and their derivatives (HI, OI, SP, and PI).

Kerogen Type

Characterization of organic matter in source rocks can be accomplished through a number of parameters of which the Rock-Eval pyrolysis measurements and their derivatives could serve as important criteria. These basic kerogen types could be identified from hydrogen indices (Tissot et al., 1984). Hydrogen Index represents the amount of hydrogen relative to the amount of organic matter present in a sample. The HI is used to characterize the kerogen type and maturation level in conjunction with the OI. The organic matter type is an important parameter in evaluating source rock potential and has important influence on the nature of the hydrocarbon products. The kerogen designation is based entirely on HI (Hunt 1996) but the kerogen quality and maturity are determined by plotting HI versus Tmax rather than HI versus OI (Fig. 5 and Fig. 10). This eliminates of OI as a kerogen type indicator (comparable to the O/C in the Van Krevelen diagram)

Table 1: Results Rock-Eval/TOC analysis from the Okobo Coal Mine in Mamu Formation Anambra Basin.

SAMPLE NUMBER	SAMPLE NAME	SAMPLE TYPE	HAWK TOC	S1	S2	Tmax	S3	HI	OI	PI	S2/S3	SP	S1/TOC *100
Unit			wt%	mg/g	mg/g	°C	mg/g					mg/g	
1	OKA1B	Coal	52.49	2.26	129.26	421	8.78	246	16	0.02	14.72	131.52	4
2	OKA1T	Coal	51.80	1.60	126.62	418	8.85	244	17	0.01	14.31	128.22	3
3	OKB1B	Coal	50.95	1.97	148.09	423	7.10	290	13	0.01	20.86	150.06	3
4	OKB1M	Coal	52.81	3.50	206.46	421	6.51	390	12	0.02	31.71	209.96	6
5	OKB1T	Coal	50.95	3.51	172.82	417	7.31	339	14	0.02	23.64	176.33	6
6	OKC1B	Coal	49.02	2.21	133.21	423	6.64	271	13	0.02	20.06	135.42	4
7	OKC1T	Coal	49.29	1.93	130.71	420	8.54	265	17	0.01	15.31	132.64	3
8	OKD1B	Coal	48.23	1.41	124.20	421	6.93	257	14	0.01	17.92	125.61	2
9	OKD1T	Coal	51.20	2.14	140.39	422	6.72	274	13	0.02	20.89	142.53	4
10	OKA2	Shale	6.17	0.32	12.39	433	2.12	200	34	0.03	5.84	12.71	5

11	OKA4	Shale	0.78	0.05	0.45	435	0.47	56	60	0.09	0.96	0.50	5
12	OKB2	Shale	7.18	0.38	13.28	423	1.31	184	18	0.03	10.14	13.66	5
13	OKB4	Shale	5.73	0.28	11.71	425	1.20	204	20	0.02	9.79	11.99	4
14	OKC2-A	Shale	4.77	0.19	9.46	433	1.32	198	27	0.02	7.17	9.65	4
15	OKC2-B	Shale	5.45	0.22	12.95	431	1.30	237	23	0.02	9.96	13.17	4
16	OKC4B	Shale	7.68	0.32	21.99	429	1.18	286	15	0.01	18.64	22.31	4
17	OKC4T-A	Shale	7.05	0.27	17.30	430	1.22	245	17	0.02	14.18	17.57	3
18	OKC4T-B	Shale	6.66	0.26	16.45	429	1.12	247	16	0.02	14.18	16.71	3
19	OKD2B	Shale	2.76	0.18	2.52	437	1.25	91	45	0.07	2.02	2.70	6
20	OKD2T	Shale	1.72	0.13	1.66	439	1.01	96	58	0.07	1.64	1.79	7

Type I organic matter is hydrogen rich (HI greater than 600mg HC /g TOC) and this is considered to be predominantly oil-prone, Type II organic matter is characterized by HI between 350 and 600mg HC/gTOC and this could generate both oil and gas at the appropriate level of maturity. Type III organic matter is characterized by low to moderate HI of between 75 and 200mg HC/g TOC and could generate gas at the appropriate level of thermal maturity. Type IV organic matter normally exhibit very low HI less than 50mg HC/g TOC; are produced under very oxic environment and are generally inert (Tissot and Welte, 1984). However, Peters (1986) suggested that at a thermal maturity of vitrinite reflectance of 0.6% (Tmax 435^{0}C) rocks with HI above 300mg HC/gTOC generates oil;

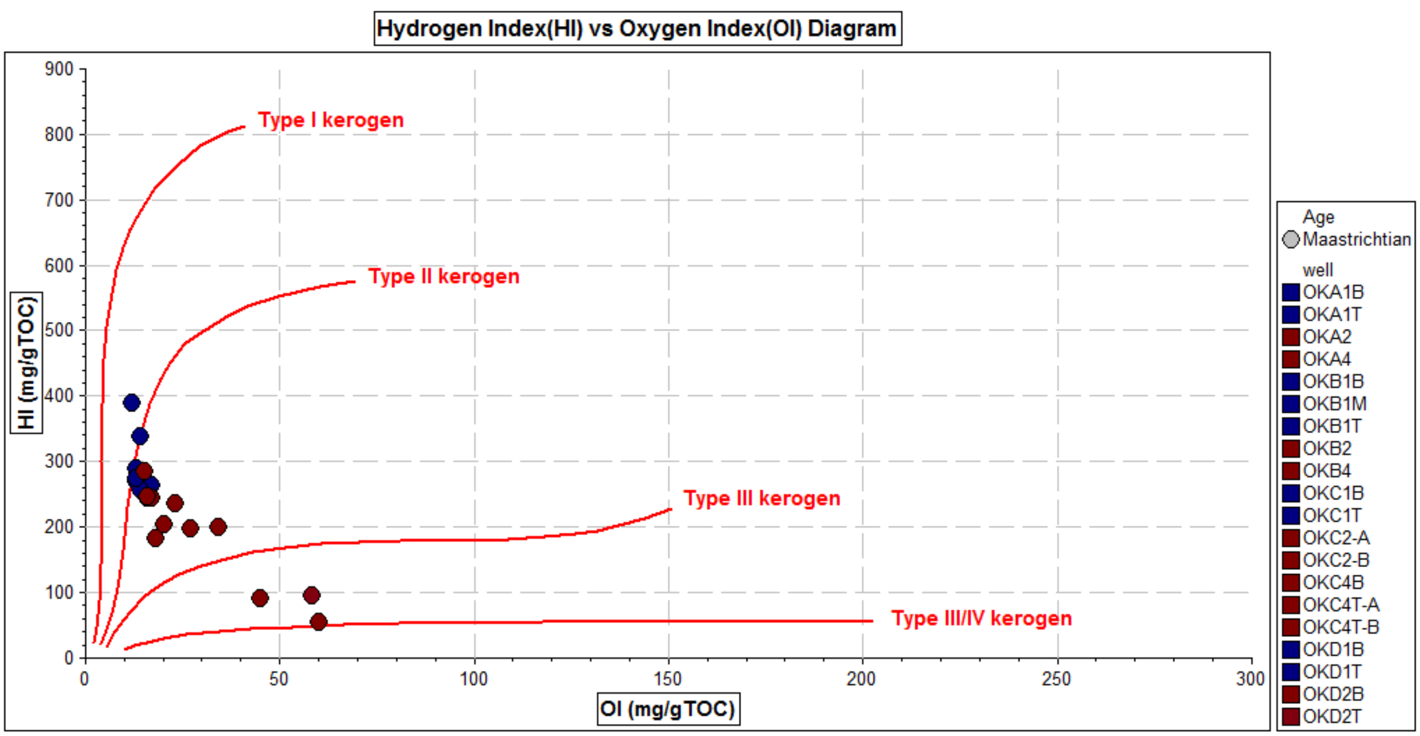

Fig. 5. Plot of HI versus OI for the interpretation of kerogen type of the Mamu Formation

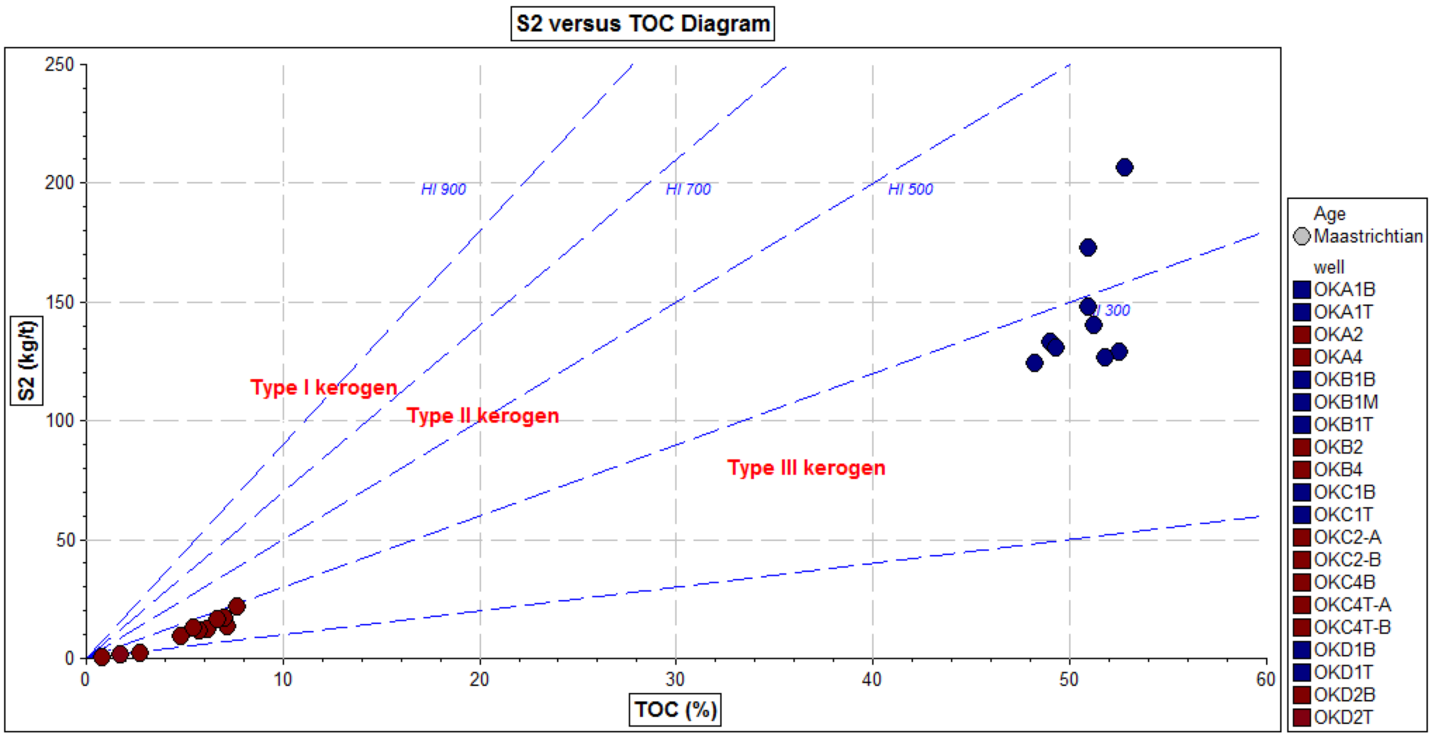

Fig. 6. Plot of S_2 versus TOC for the interpretation of kerogen type of Mamu Formation (Langford and Blanc-Valleron 1990)

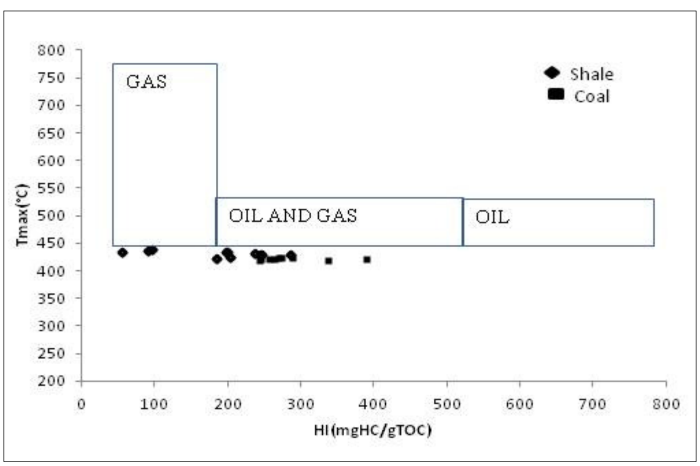

Fig. 7. Plot of Tmax versus HI of the Mamu Formation showing their relative hydrocarbon potential level

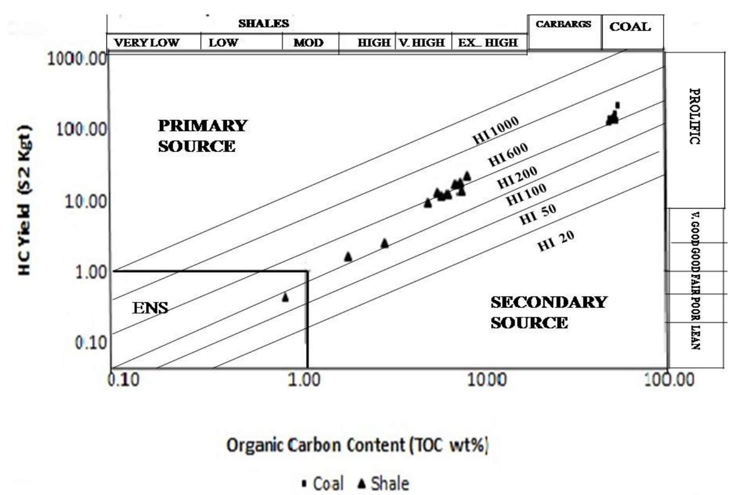

Fig. 8. Summary of the source rock quality on the basis of Rock-Eval parameters, Hydrocarbon yield (S2KgHC/ton of rock) against Total Organic Carbon (TOC wt %) of the studied samples. Notice that this classifies coal as primary hydrocarbon source.

those with HI between 300 and 150 generates oil and gas; while those with HI between 150 and 50 generates only gas and those with HI less than 50 are inert. Thus, it is imperative to determine the kerogen types of the source rock as they have first-order control on the hydrocarbon products after maturation.

In the Okobo study area, the HI values of coal range from 244mgHC/gTOC – 390mgHC/gTOC with an average value of 286mgHC/gTOC indicating a

Type II kerogen. Whereas, the HI values of shale range from 56mgHC/gTOC – 286mgHC/gTOC with an average of approximately 186mgHC/gTOC, indicating a Type II/III kerogen. The HI values of both coal and shale are generally higher in the southern part of the Okobo coal mine as compared with the HI values of the northern part of the mine. However, both coal and shale sample assemblage from Okobo area can be consider a potential source rock for oil and gas generation because of the high value of HI satisfying the threshold of oil and gas generation. The Type III kerogen suggests organic matter derived from terrestrial source which can generate mainly gas with little or no oil.

The modified Van Krevelen diagram (HI versus OI) (Fig. 5) shows that almost all the samples consist predominantly of Type II and III kerogens, which are capable of generating gas-oil and gas respectively at appropriate maturation. The plot of S2 versus TOC (Fig. 6) to show the good correlation of hydrocarbon yield (S2) and total organic carbon content (TOC) was also made and help to substantiate the kerogen typing as type II and III.

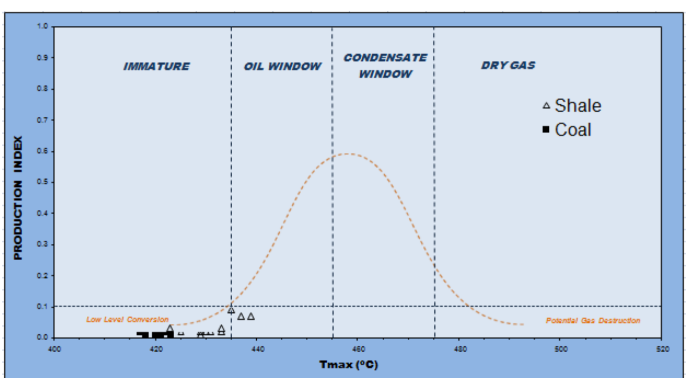

Fig. 9. Plot of the Production Index versus Tmax for the interpretation of thermal maturity of the studied samples

Hydrocarbon Generation Potential

The Rock-Eval pyrolysis data set with the derivatives determined from the programmed heating of samples in inert atmosphere provide an added evidence by direct estimation of the hydrocarbons that evolved freely ; considered as S1; the generable hydrocarbons directly from kerogen cracking known as S2. The values of S1 + S2 herein represents the rocks total hydrocarbon generation potential comparable with the assessment criteria of Dymann et al., (1996) with the suggestion of hydrocarbon yield S1 + S2 less than 2mg HC /g rock typifying little or no oil potential with some potential for gas; S1 + S2 from 2 to 6 mg HC /g rock indicating moderate or fair source rock potential and above 6 mg HC / g rock suggesting good to excellent source rock potential. The threshold of S1 + S2 greater than 2.5 mg HC /g rock can be considered as a prerequisite for classification as a possible oil source rock and provide the minimum oil content necessary near the top of the main stage of hydrocarbon generation to saturate the pore network and permit expulsion (Akande et al., 2011).

The total hydrocarbon yield SP in the coal samples of Okobo area range from 125mgHC/gTOC to 209.96mgHC/gTOC with an average value of 148.03mgHC/gTOC. This suggests excellent source rock potential in the area. The total hydrocarbon yield SP in the shale samples of Okobo area range from 0.50mgHC/gTOC to 22.31mgHC/gTOC with an average value of 11.16mgHC/gTOC. This suggests good to excellent source rock potential in the area. The most elevated hydrocarbon yield of the samples analysed is a coal sample with sample number OKB1M in the southern part of the coal mine with 209.96mgHC/gTOC. This value also correspond with the highest TOC and highest HI value in all the samples and this provides a good correlation between the S2 and TOC values and to

some extent with the HI values from the Mamu coal assemblage (Fig. 7 and Fig. 8).

Thermal Maturity

Tmax value represents the temperature at which the largest amount of hydrocarbons is produced in the laboratory when a whole rock sample undergoes a pyrolysis treatment gives an indication on the thermal maturation of the source rock. The degree of thermal alteration of organic matter due to heating provides an indication of source rock organic matter type and presence of excess free hydrocarbon together with the other factors like mineral matter, content, depth of burial and age (Tissot and Welte, 1984). Degree of thermal evolution of the Mamu Formation was deduced from Tmax and Production index. Tmax values from pyrolysis experiments are considered as a simple measure of the sample level of thermal maturity as all the total organic carbon reached the minimum threshold of 0.5 wt% expected for any rock (Hunt, 1979). Although production index (PI) can provide an estimation of thermal maturity, this can only be considered appropriately as reliable thermal maturity indicators when hydrocarbon yields are significantly above background levels.

Combining and finding relations between the essential Rock-Eval parameter, Tmax, and calculated Rock-Eval parameter, PI (Fig. 9), is a valuable method for indicating the thermal maturity of organic matter. The following relations between Tmax and PI are observed:

1. Immature organic matter has Tmax and PI values less than 430°C and 0.10, respectively;
2. Mature organic matter has a range of 0.1 the top of oil window, Tmax and PI reach 460°C and 0.4, respectively;
3. Mature organic matter within the wet gas values greater than 0.4; and
4. Post-mature organic matter usually has a high PI value and may reach 1.0 by the end of the dry zone (Peters, 1986, Peters and Cassa 1994, and Bacon et al., 1993)

In general, PI and Tmax values less than 0.1 and 435^0C respectively indicate immature organic matter and a Tmax greater than 460^0C represents the wet gas zone. The increase of maturity level of organic matter corresponds to an increase in Tmax. This phenomenon is related to the nature of chemical reactions that occur through thermal cracking. The weaker bonds survive until higher temperatures in the late stage (Whelam and Thompson-Rizer, 1993).

Tmax of the Okobo rock sequence coal ranges from 417^0C-423^0C with an average of approximately 421^0C. This indicates that the coals of the area are thermally immature to generate and expel both liquid and gas hydrocarbon. Whereas, the Tmax values of the shale samples ranges from 423^0C – 439^0C with an average of approximately 431^0C. This suggests that the shales of the area thermally fall within slight early maturity stage. More so, the production index values of both coal and shale samples from the area fall below the threshold value of 0.1 with three (3) shale samples from the northern part of the area having average PI value of 0.08. This corroborates the thermally marginal maturity of the shale samples from Tmax values.

The plot of production index versus maturity (based on Tmax) of the samples analyzed shows that the source rock is immature to marginal mature to generate any hydrocarbon (Fig. 9). A relationship between Tmax and Production Index as shown in plot of Tmax versus Production Index (Fig. 11) shows the hydrocarbon generation potential zone and are non-indigenous (migrated) hydrocarbons. This indicates that the samples are immature.

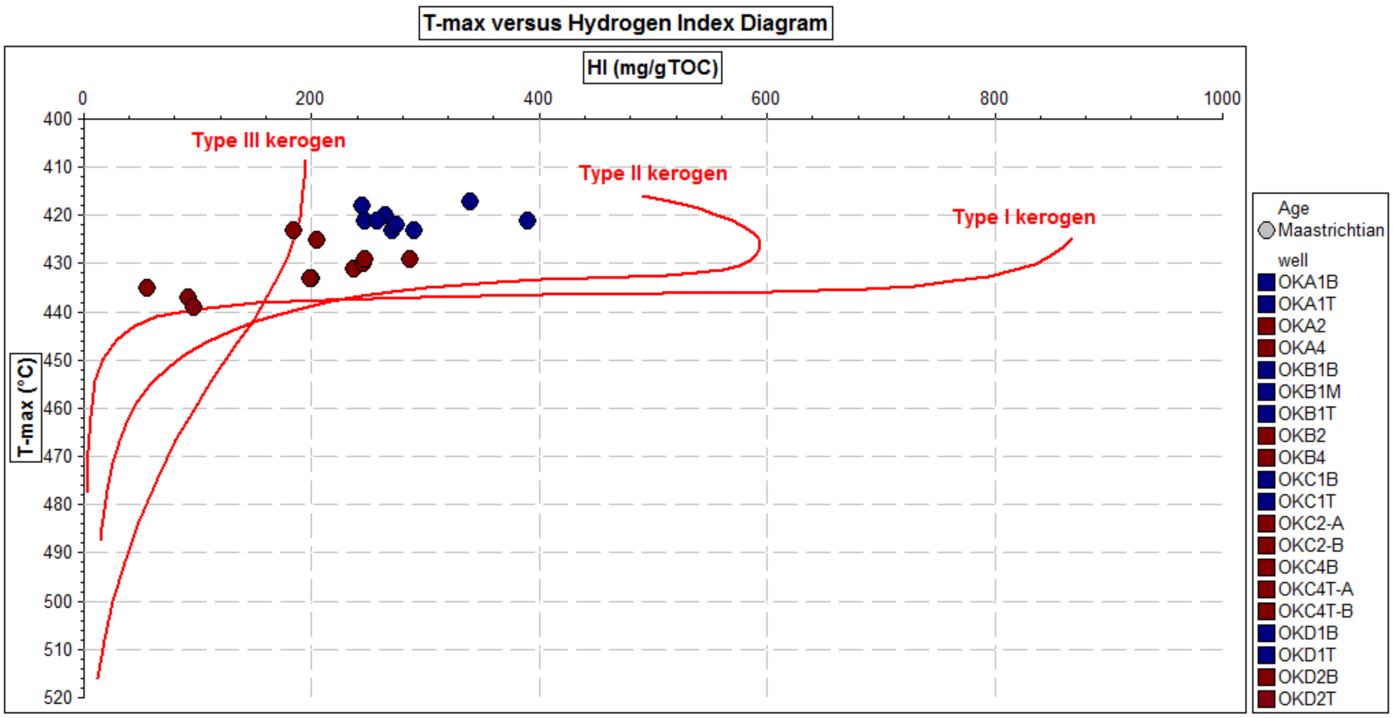

Fig. 10. Plot of the HI against Tmax for the interpretation of the kerogen type and maturity of the studied samples.

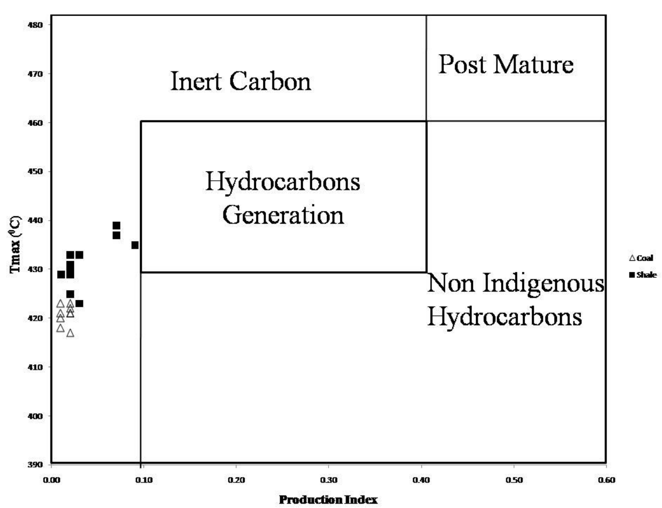

Fig. 11. Plot of Tmax versus Production Index showing the hydrocarbon generation zone

Conclusions

The investigated source rock units of the Maastrichtian Mamu Formation at Okobo area by Rock-Eval pyrolysis suggest that the shales and coals have good source rock potential having attained the threshold of 0.5%wt required for petroleum source rocks. The values of the HI (average of 286mgHC/gTOC for coals and 186mgHC/gTOC for shale) and different plots reveal that the shale are mostly Type III organic matter while the coal are mostly type II/III kerogen organic matter have very good to excellent potential to generate both liquid and gaseous hydrocarbon. The Tmax values range from 417 to 439^{0}C which shows thermal immaturity to early maturity.

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